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In the Matter of an Application of Atlantic Richfield Canada Ltd, Canada-C 1
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ERCB REPORT 71-F-OG

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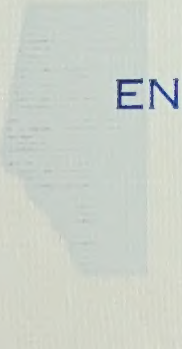
IN THE MATTER OF AN APPLICATION OF ATLANTIC RICHFIELD CANADA LTD., CANADA-CITIES SERVICE, LTD., GULF OIL CANADA LIMITED AND IMPERIAL OIL LIMITED UNDER PART 8 OF THE OIL AND GAS CONSERVATION ACT



ENERGY RESOURCES CONSERVATION BOARD
603 SIXTH AVENUE SOUTH WEST • CALGARY 1, ALBERTA

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REPORT TO
THE LIEUTENANT GOVERNOR IN COUNCIL

IN THE MATTER OF AN APPLICATION OF ATLANTIC RICHFIELD CANADA LTD., CANADA-CITIES SERVICE, LTD., GULF OIL CANADA LIMITED AND IMPERIAL OIL LIMITED UNDER PART 8 OF THE OIL AND GAS CONSERVATION ACT

DECEMBER
1971

ENERGY RESOURCES CONSERVATION BOARD
603 SIXTH AVENUE SOUTH WEST • CALGARY 1, ALBERTA
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I INTRODUCTION

This report deals with the application of Atlantic Richfield Canada Ltd., Canada-Cities Service, Ltd., Gulf Oil Canada Limited and Imperial Oil Limited for the amendment of Approval No. 1223, to allow for the production of 45,625,000 barrels per year of synthetic crude oil and 2,000,000 net barrels per year of residual fuel and by striking out clauses 7, 10 and 14. The effect of the latter proposed amendment would be to permit the marketing of the synthetic crude oil on the basis of the life index criterion of the Oil Sands Development Policy(1) as tabled in the Legislative Assembly of the Province on February 20, 1968. The application was heard by the Energy Resources Conservation Board on September 21 and 22, 1971, with G. W. Govier, P. Eng., D. R. Craig, P. Eng. and Vernon Millard sitting.

The Applicants

Approval No. 1223 was issued on September 30, 1969, in the names of Atlantic Richfield Company, Cities Service Athabasca, Inc., Imperial Oil Limited and Royalite Oil Company, Limited. Effective September 23, 1969, the assets in Canada of Atlantic Richfield Company were transferred to its wholly owned subsidiary, Atlantic Richfield Canada Ltd. Effective December 31, 1970, Cities Service Athabasca, Inc., a wholly owned subsidiary of Cities Service Company, transferred its assets to Canada-Cities

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(1) The policy is set out in Appendix A in OGCB Report 68-C. Report on an Application of Atlantic Richfield Company, Cities Service Athabasca, Inc., Imperial Oil Limited and Royalite Oil Company Limited. Under Part VIA of The Oil and Gas Conservation Act. December, 1968.

Service, Ltd., another wholly owned subsidiary of Cities Service Company. On April 18, 1969, Royalite Oil Company, Limited was amalgamated into Gulf Oil Canada Limited. The present applicants have asked the Board to update the names of the approval holders in any amendment that may follow the subject application. Syncrude Canada Ltd., (hereinafter referred to as "Syncrude", continues to serve as operator for the participant companies in the development and operation of the project.

Appearances

The persons named in Table I-1 appeared at the hearing. Canadian Fina Oil Limited and Texaco Exploration Canada Ltd. appeared only for the purpose of cross-examination and argument.

TABLE I-1

APPEARANCES

	Abbreviation of Name used in Report	Represented by	Witnesses
Atlantic Richfield Canada Ltd.	Atlantic Richfield	J. H. Laycraft, Q.C.	J. A. Cogan (of Imperial) G. A. Connell, P.Eng. (of Gulf) R. G. Daniel (of Atlantic Richfield) J. G. Gainer, P.Eng. (of Gulf) G. R. Gray, P.Eng. (of Syncrude) R. R. Goforth (of Syncrude) F. K. Spragins, P.Eng. (of Syncrude)
Canada-Cities Service, Ltd.	Cities-Service		
Gulf Oil Canada Limited	Gulf		
Imperial Oil Limited	Imperial		
Canadian Fina Oil Limited	Canadian Fina	G. W. Brown	
Independent Petroleum Association of Canada	IPAC	R. A. MacKimmie, Q.C.	A. H. Ross (of IPAC and Western Decalta Petroleum Ltd.)
Texaco Exploration Canada Ltd.	Texaco	J. M. Geunther	
Board Staff		D. N. Blades, P.Eng. J. S. Rimell	

II BACKGROUND TO THE APPLICATION AND DEFINITION OF ISSUES

Background

The applicants or their predecessors had been granted permission, through the issuance of Approval No. 1223 on September 30, 1969, to produce 18,250,000 barrels per year of synthetic crude oil, 9,125,000 barrels per year of specialty oils and 1,825,000 barrels per year of naptha with the recovery of saleable hydrocarbon products to commence not earlier than July 1, 1976, and not later than January 1, 1977.

Approval of the project followed consideration of the second amended revision of the initial application received by the Board in 1962.

The first application was heard in January, 1963, and was for the production of 100,000 barrels per day of synthetic crude oil with production to commence in 1969. The details of the decision, which deferred final consideration of the application and proposed items under which an amended application would be considered, appear in the Board's report of October 1963(1).

The first amendment to the application was considered by the Board at a hearing in June and August of 1968. This amendment was for production rates of 18,250,000 barrels per year of synthetic crude oil, 9,125,000 barrels per year of specialty oils and 1,825,000 barrels per year of naptha with production to commence in 1973. The decision in the Board report of December 1968 (2) was to the effect that the application could not be granted but that the Board, with the approval of the Lieutenant Governor in Council, would be prepared to grant the application if the applicants could satisfy the Board on certain matters at a hearing to be called in November 1969. Prior to a decision by the Lieutenant Governor in Council on the December 1968 report the applicants made a submission to the Lieutenant Governor in Council which, in part, proposed a delay in the commencement of the proposed operations by three years. The submission was referred to the Board, and it subsequently issued a report in March 1969 (3) amending the December 1968 report. The March 1969 report specified a new set of conditions under which the Board, with the approval of the Lieutenant Governor in Council, would be prepared to grant the application.

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(1) Report to the Lieutenant Governor in Council with respect to the Applications of Cities Service Athabasca Inc. and Shell Canada Limited. October, 1963.

A second amendment to the initial application was considered by the Board at a hearing in May of 1969. This amendment to the application was for the same rates of production as specified in the first amendment but proposed a delay in the production operations until mid-1976. The Board decision, subject to approval of the Lieutenant Governor in Council, to grant the application was contained in a report of September 1969(4), and was approved by the Lieutenant Governor in Council. Approval No. 1223 was subsequently issued.

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(2) OGCB Report 68-C. Report of an Application of Atlantic Richfield Company, Cities Service Athabasca, Inc., Imperial Oil Limited and Royalite Oil Company, Limited under Part VIA of The Oil and Gas Conservation Act. December, 1968.

(3) OGCB Report 69-B. Supplement to the Report of an Application of Atlantic Richfield Company, Cities Service Athabasca, Inc., Imperial Oil Limited and Royalite Oil Company, Limited under Part VIA of The Oil and Gas Conservation Act. March 1969.

The application now under consideration is for an amendment of Approval No. 1223 to allow for an increase in the rate of production and to provide for the marketing of the synthetic crude oil under the life index criterion of the Oil Sands Development Policy.

Definition of the Issues

The application proposed changes in the area to be mined and the method of mining and transporting the oil sands material. Marketing of the proposed increased amount of synthetic crude oil under the life index criterion was supported by a presentation of supply and demand estimates for Canadian and Alberta crude oil. Only those items which constitute changes from the previous application will be considered in this report. These are dealt with under the following matters of principal interest:

1. Conservation and Technical Matters
2. Environmental Matters

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(4) OGCB Report 69-C. Report of an Application of Atlantic Richfield Company, Cities Service Athabasca, Inc., Imperial Oil Limited and Royalite Oil Company, Limited, September, 1969.

3. Qualification under the Oil Sands Development Policy
4. Capacity Constraints on Alberta Conventional Production.

III SUBMISSION OF THE APPLICANTS

In this section the submission of the applicants is summarized having regard for the first three matters of principal interest. Further details are included in Sections V and VI of this report. The application did not deal with the matter of capacity constraints on Alberta conventional production which was introduced in an intervention and is described in Section IV.

The applicants submitted that the drilling of additional core holes since the 1968 application(1) has delineated larger mineable reserves in the northwestern portion of the lease. An expansion of the plant area to accommodate larger plant facilities, coupled with a change in area to provide more regular pit geometry for ease of transportion and access to the plant, resulted in furhter changes from the previously proposed mining areas.

The proposed mining and materials conveying scheme has been changed from a scraper, belt conveyor system to a dragline, rail haulage system. Walking draglines would be used to cast the overburden and centre reject material into the previously mined area and the oil sands onto a storage pile for transfer to the plant. Oil sands would then be moved from the pile by a bucket wheel reclaimer and short belt conveyor into rail cars for transport to the plant.

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(1) Application No. 4000. Application to the Oil and Gas Conservation Board under Part VIA of The Oil and Gas Conservation Act by Atlantic Richfield Company, Cities Service Athabasca, Inc., Imperial Oil Limited and Royalite Oil Company Limited. May 9, 1962. Amended to May 3, 1968.

The applicants propose to dispose of tailings into a retention pond for an initial period of operation and then to deposit the tailings on top of windrows of overburden in the mined out area. The water draining from these tailings and carrying some fine material would be pumped from the mined out area into the retention pond for recycle.

The applicants submitted that off-site gas would be used to fire process heaters, and consequently the plant would not maintain an overall energy balance. Because of this there would be a heavy residual fuel oil from the conversion of the bitumen to synthetic crude in excess of that required by the plant operation. The applicants propose the use of this excess in the generation of power for off-site sale.

The applicants submitted that the emission of gaseous pollutants to the atmosphere at the increased throughputs proposed would be kept within acceptable limits through the use of a 400-foot stack to vent the effluents from the sulphur plant incinerator and the power plant. Particulate emission rates would be kept within provincial standards by the use of a cyclone burner which would retain as a slag a large portion of the mineral content of the boiler fuel at the power plant.

All of the water used in the process would be contained in the tailings retention pond. The Mildred Lake basin would be utilized as a fresh water storage and cooling pond. The water from these ponds would not be allowed to enter the Athabasca River.

The applicants proposed to carry out a program of revegetation on the dikes and mined out areas of the lease.

The applicants presented estimates of supply and demand for both United States and Canadian crude oil and determined a life index for Alberta crude oil on the basis of these estimates.

The demand for crude oil in the United States was predicted by the applicants to increase from 14.5 million barrels per day in 1970 to 24.0 million barrels per day between 1970 and 1980, whereas the estimate of United States producing capability, excluding North Slope production, indicated a decline of about 1.3 million barrels per day in the same period. The applicants' production estimate for the North Slope was not submitted but they stated that the High Alaska case presented by the Board in OGCB Report 69-C(2) was compatible with the upper range of Atlantic Richfield's estimates. As a result of these predictions the United States deficiency of conventional crude oil from indigenous sources was calculated to increase substantially in the decade under consideration.

The total demand for Canadian crude oil west of the National Oil Policy Line was forecast to almost double in the 1970 to

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(2) Report of an Application of Atlantic Richfield Company, Cities Service Athabasca, Inc., Imperial Oil Limited and Royalite Oil Company, Limited. September 1969.

1980 period. The applicants projected that the demand for Canadian crude oil would be met in part by increased production from the Yukon and Northwest Territories commencing in the latter part of this decade. Total production from British Columbia, Saskatchewan, Manitoba and Ontario was predicted to decrease in this period by approximately 120 thousand barrels per day. It was assumed that any production from the Canadian East Coast and Arctic Islands would be marketed initially in the area east of the National Oil Policy Line.

The applicants predicted Alberta conventional crude oil production, based on a limiting life index of ten years for prorated crude oil, to increase by about 625 thousand barrels per day between 1970 and 1980. Synthetic crude oil production rates were forecast to increase to 300 thousand barrels per day by 1980.

The applicants forecast that reserves growths for Alberta crude oil would be less than predicted as the low case by the Board in OGCB Report 69-C. The growth in initial proved reserves for proratable crude oil reflected a declining rate of reserves additions and was estimated to reach 12,745 million barrels by 1977.

The life index for Alberta proratable crude oil was calculated by the applicant from the estimated demand and reserves growth. This resulted in a declining life index with the critical 12- to 13-year life index levels referred to in OGCB Report 69-C, occurring sometime between 1973 and 1974. It was the applicants conclusion that granting of their application "under the life index criterion of the Oil Sands Development Policy is fully warranted".

IV SUBMISSION OF INDEPENDENT PETROLEUM ASSOCIATION OF CANADA

IPAC intervened on the basis of its concern regarding the possible lack of pipe line capacity out of Alberta to transport the production of conventional crude oil and the increased volumes of synthetic crude oil. The intervener stated that additional pipe line capacity would be required before the applicants commence production in order that this production not limit the transportation of conventional crude oil outside of Alberta. IPAC contended that a provision should be included in any approval following this or similar applications to ensure that conventional crude oil receive priority in the event a shortage in extraprovincial pipe line capacity from Alberta should develop.

V CONSERVATION AND TECHNICAL MATTERS

(1) Views of the Applicants

The applicants calculated reserves of 2,440 million barrels of bitumen in the three mining areas, A, B and C, illustrated by Figure 1. Changes in the proposed mining areas from those proposed in the 1968 application resulted from additional mineable reserves being defined in Area B and a reduction in the size of Area C to allow for an increase in plant size and to provide for more regular pit geometry. The areas designated as U_1, U_2 and U_3 on Figure 1 were said by the applicants to be unmineable. There would be sufficient reserves in Areas A and B to supply the plant with feed for the 25-year life of Approval No. 1223.

Losses in mining recovery would be due primarily to bitumen included in the centre reject material and side slopes on the boundary walls. Side slope losses at the pit walls were estimated by the applicants to be 1.0 per cent of the bitumen in place compared to 2.0 per cent contemplated in the 1968 application. The distinction between mineable and reject material, would be made on a visual basis with confirmation by in-pit analyses.

The applicants stated that reject losses of 8.3 per cent of the bitumen in place are expected in the initial mining area. This loss is 1.0 per cent higher than that indicated for the initial mining area in the previous application and is due to the inclusion of lower grade material in the southern part of the area. Since the side slope losses of the boundary wall will be less as a result of the dragline method of mining, the net effect

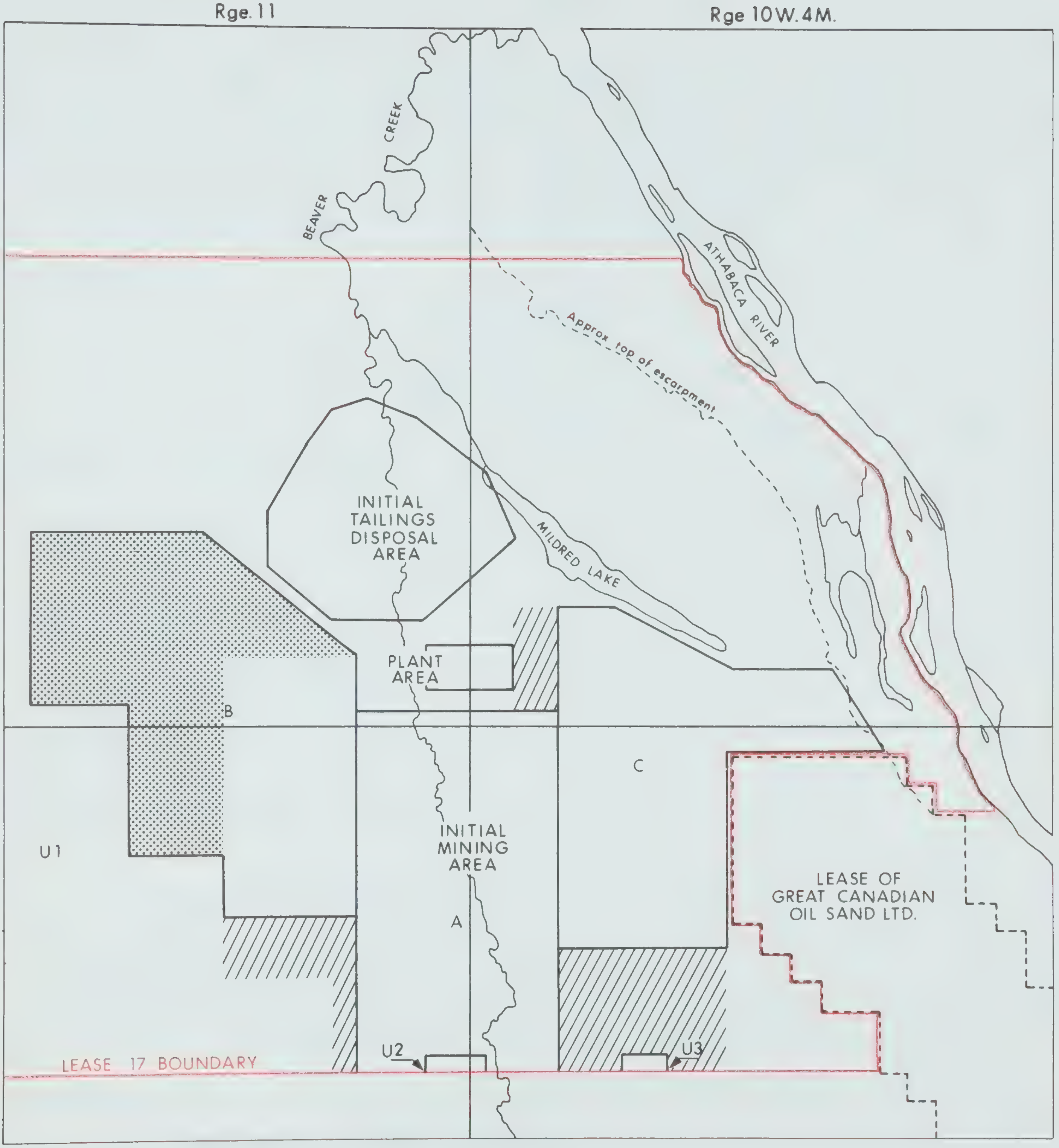

FIGURE 1 - PROPOSED MINING AREAS
(Most areas shown are approximate)

Scale: 0 1 2

▨ - Deletion from 1968 propsal

▒ - Addition to 1968 propsal

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of these losses was a predicted mining efficiency in Area A about equal to that predicted for the initial mining area in the 1968 application. The reserves, feed gravity and mining recoveries estimated for Areas A, B and C are set out in Table V-1.

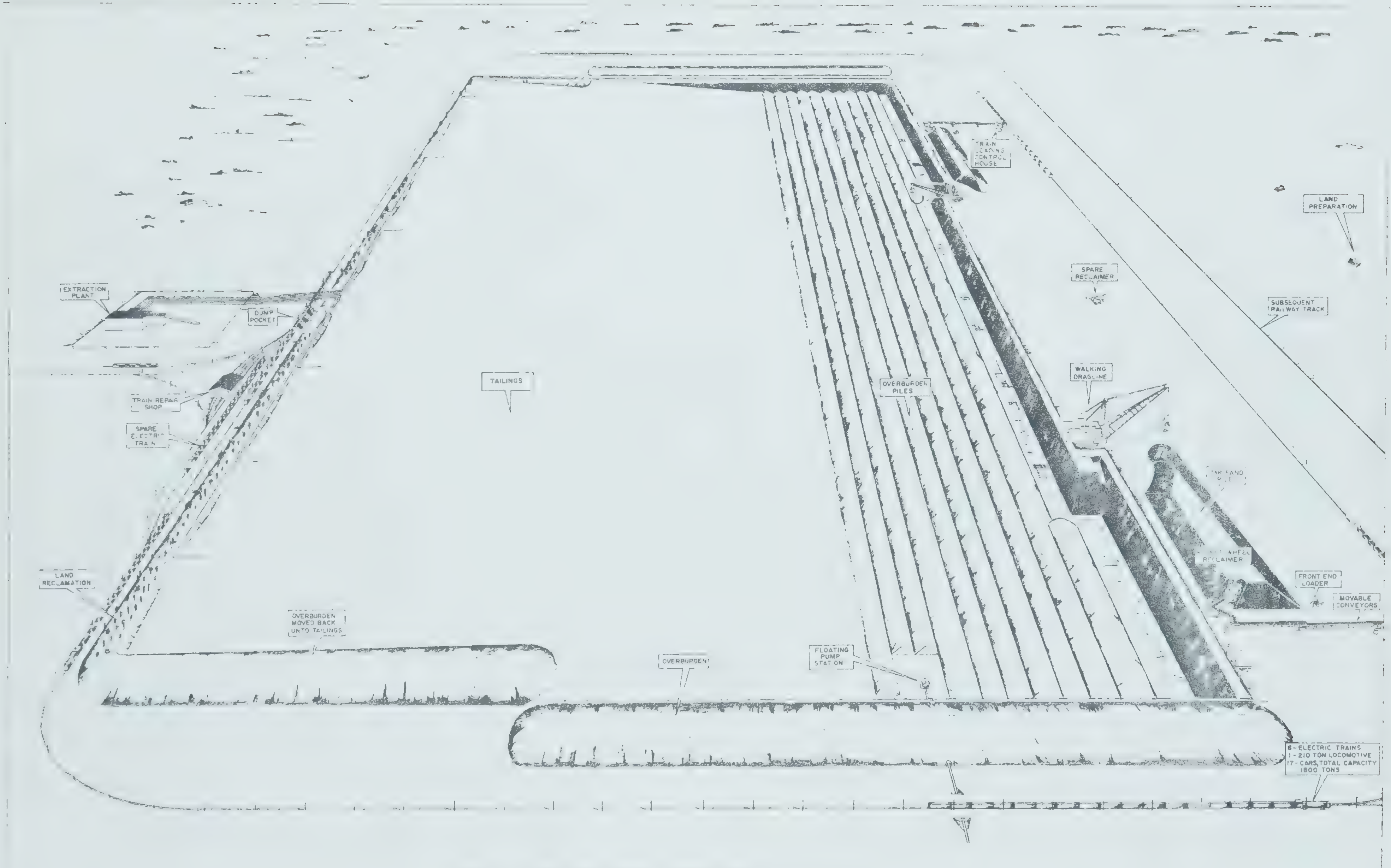
TABLE V-1

RESERVES AND MINING EFFICIENCIES

	Area A	Area B	Area C
Crude bitumen in place, bbl	807,000,000	821,000,000	816,000,000
Mining recovery, weight per cent	90.7	85.3	87.6
Crude bitumen in plant feed, bbl	732,000,000	700,000,000	714,000,000
Average crude bitumen saturation in plant feed, weight per cent	11.8	11.5	11.8
Average fines content in plant feed, weight per cent	11.4	12.4	11.9

In their submission the applicants stated that the reserves covered by the proposed tailings retention pond, estimated to be 990 million barrels of bitumen, would not be rendered unmineable since the waste material in this pond could be displaced to the mined out area. They did not expect this could be done until other mineable reserves had been utilized.

The dragline and rail haulage mining and transporting system proposed by the applicants is illustrated by Figure 2 taken from the submission of the applicants. The draglines to be used in



VIEW OF DRAGLINE MINING OPERATION AFTER YEAR 6

FIGURE 2 — MINING AND SOLIDS DISPOSAL
(REPRODUCED FROM APPLICANTS' SUBMISSION)

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the mining operation would have bucket capacities of about 130 cubic yard capacity, near the upper size limit of such machines currently available for use. The applicants stated that the use of draglines for mining would provide for the recovery of the oil sand located in the irregularities of the Devonian surface underlying the deposit and would reduce side slope losses on the pit and lease boundary walls. They pointed out that the maximum digging depth of the machines, 210 feet, exceeded the maximum depth of oil sands of 190 feet encountered to date on this lease. Six trains would be utilized to haul the mined material to the plant, each being made up of seventeen 100-ton side dump cars.

The applicants stated that the bitumen extraction and froth treatment operations would be enlarged but essentially the same as those previously described. The predicted recovery efficiency of this process of the operation was estimated to decrease by 0.8 per cent to 92.9 per cent due to the increased rate of mining and the inclusion of feed of a higher fines content.

Research programs carried out by the applicants indicated that the settling rate of the fines from the water in the retention pond would be sufficient to provide a recycle of one-half the water required in the extraction process.

Upgrading of the bitumen would be accomplished through the use of the hydrovisbreaking and subsequent hydrotreating process described in the 1968 application. The applicants submitted that an increased conversion level in the upgrading process would result in an increase in efficiency from 87.2 volume per cent previously calculated to 89.4 volume per cent.

Table V-2 is a summary of the hydrocarbon recoveries for mining areas A, B and C on a weight per cent basis, as presented by the applicants:

TABLE V-2

LOSSES AND RECOVERY EFFICIENCIES
(Weight per cent based on total crude bitumen in place)

	Losses		Recovery		
Step	%	Descriptive	%	Descriptive	Cumulative Recovery,%
Mining	12	reject material and boundary walls	88	plant feed	88
Extraction & Froth Treatment	7.1	oversize reject and tailings	92.9	raw bitumen	82
Upgrading	24	fuel, sulphur and hydrogen plant feed	76	synthetic crude oil	62

the applicants expressed the intention of using off-site gas as fuel in the process heaters to that, at the level of bitumen upgrading, the plant would not realize an energy balance. Approximately 57 million cubic feet of natural gas per day would be required by the plant. Considering the fuel requirements needed to supply power to the plant, approximately 4900 barrels per calendar day of excess residual fuel would be produced. The level of bitumen conversion and consequently the amount of residuel fuel produced, was chosen having regard for the guarantees of the licenser and the fact that this is a new area of application of the hydrovisbreaking process. It is the applicants' expressed intention to evaluate higher stages of conversion as experience is obtained in this area.

The applicants proposed to use the excess residual fuel from the hydrovisbreaking process for the generation of approximately 150 megawatts of electric energy for off-site sale. They pointed out that construction of such a power plant would not likely be undertaken until it could be demonstrated that the required amount of residual fuel would be available.

(2) Views of the Board

An evaluation of the reserves in Areas A, B and C, by the Board staff indicated general agreement with the bitumen in place and recoverable bitumen estimates presented by the applicants.

The Board continues to consider the reserves under the tailings retention pond to be economically mineable under present overburden conditions and notes that the applicants intend to carry out further evaluation drilling programs in this area prior to the disposition of waste material. The Board believes that it is the applicants' responsibility to conduct their operation in a manner which will provide for the mining of the reserves in this area.

The Board accepts that the proposed mining system will result in improved recovery over the system previously proposed, by minimizing pit losses and facilitating the recovery of oil sands from the irregularities in the Devonian surface.

The Board is satisfied with the recovery efficiencies predicted for the extraction and upgrading phases of the operation and with the expected overall recovery by the scheme of 62 per cent, about one percent higher than previously expected by the applicants. The Board accepts that the planned modification by the applicants of the process previously approved could result in the production of an excess heavy residual fuel. Should the Board issue an approval as a result of this application a condition requiring that this by-product be stored or suitably marketed would be included.

The construction of a power plant for the generation of electric energy in excess of the requirements of the project and the facilities for off-site sales will be considered by the Board if and when suitable applications are made under The Hydro and Electric Energy Act.

VI ENVIRONMENT MATTERS

(1) Views of Applicants

The applicants stated that the overall sulphur recovery would be increased from that proposed in the 1968 application so that no increase in sulphur dioxide emissions would result from the increase in production rate from 80,000 barrels per day to 125,000 barrels per day. Unrecovered sulphur and sulphur compounds would be incinerated to sulphur dioxide and exhausted to the atmostpher through a 400-foot stack at a minimum gas exit temperature of 500 degrees Fahrenheit. The applicants said they chose the 400-foot stack because the maximum ground level concentration of sulphur dioxide calculated for a stack of this height was found to be 0.15 parts per million, one-half the provincial standard for this area. They stated that the calculated concentrations increased with wind speed but would not exceed 0.15 parts per million at wind speeds up to 30 miles per hour under neutral atmospheric conditions.

The applicants evaluated the combined effect on ground level sulphur dioxide concentrations of their proposed plant and the existing plant in the area. This evaluation indicated that under the critical condition of west-north-west winds (which would parallel the line joining the two plants) the ground level concentration of sulphur dioxide could exceed the provincial standard of 0.30 parts per million. Meterological data obtained for the area indicates that the critical west-north-west winds occur less than five per cent of the time. The applicatns indicated that if it became apparent, under actual operating conditions, that the overlapping of the plumes posed a problem, they could use sweet fuel to reduce sulphur dioxide emissions or raise the stack discharge temperature to increase the effective stack height. The applicants stated that this problem should be studied co-operatively by operators of all plants in the area and the appropriate regulatory agencies.

The reduction of sulphur dioxide emissions through further processing of the power plant fuel, to reduce the sulphur content, the removal of sulphur oxides from the flue gas, and the substitution of natural gas for the pitch have all been studied by the applicants. They expressed the opinion that none of these alternatives would be viable, having not been adequately demonstrated from a standpoint of technical or economic feasibility.

The applicants calculated ground level concentrations of nitrogen oxides, expressed as nitrogen dioxide, that would result from the plant operation and found it to be 0.015 parts per million, well below the provincial standard of 0.30 parts per million.

The applicants stated that the particulate emission rate would also be within the provincial allowable level of 0.85 pounds per 1000 pounds of flue gas, adjusted to 50 per cent excess air. The cyclone burners proposed would slag 70 to 80 per cent of the ash in the boiler fuel. Approximately 50 per cent of the unslagged portion would be removed by the dust collector, allowing

10 to 15 per cent of the ash to be discharged. The flue gas particulate concentration resulting would be 0.54 to 0.80 pounds per 1000 pounds of stack gas adjusted to 50 per cent excess air.

The applicants proposed to install three continuously operating air pollution monitoring stations and 20 to 25 cylinder-type exposure stations. Each continuous station would be equipped to determine at ground level the atmospheric sulphur dioxide, hydrogen sulphide and particulate concentrations. Particulate levels would probably be measured using a high volume air sampler. The exposure cylinder stations would determine monthly total sulphation, hydrogen sulphide and total dust fall levels. The stations would be located in critical areas determined in consultation with the Board.

The applicants gave an undertaking that no waste liquid would be allowed to enter any moving water system. The plant would be designed for maximum water recycle, and all process effluent streams would be contained in either the mined out areas or the retention pond. Approximately one-half the plant's water requirements would be obtained by clarifying and recycling water from the retention pond. The remainder would be made up from the Mildred Lake basin.

Recharge to the Mildred Lake basin would be obtained by diversion of Beaver Creek, or by pumping water from the Athabasca River during low flow periods in Beaver Creek. During high flow periods excess water in Beaver Creek would be diverted directly to the Athabasca River.

Mildred Lake would also be utilized as a cooling pond. The applicants did not provide estimates of the cooling load that would be placed on the lake or of the rise in temperature that the water in the lake would experience.

The applicants stated the revegetation of the mined area would follow development of the final upper surface of the tailings area, but the sand surface would not reach a final contour until after about 12 years of plant operation. The applicants stated they would conduct field tests during the interim period to establish the best plant types, level of fertilization and upper surface soil composition to be used.

(2) Views of the Board

The Board staff calculated ground level concentrations of sulphur dioxide that could occur due to the proposed sulphur dioxide emission from the 400-foot stack. These calculations indicate that concentrations would increase with wind speed and would be a maximum of 0.17 parts per million at a wind speed of 15 miles per hour and a maximum of 0.23 parts per million at a wind speed of 30 miles per hour. All calculations indicate the sulphur dioxide concentrations to be below the provincial standard of 0.30 parts per million.

The Board staff evaluated the combined effect of the plume from the proposed plant and the plume from the existing plant on ground level sulphur dioxide concentrations in the area. The calculations performed indicated that concentrations would exceed the provincial standard and that 0.30 parts per million at ground level would occur with a west-north-west wind. They also indicated that the contribution to the calculated excessive ground level concentrations by the proposed Syncrude plant would be less than the contribution by the existing plant. The Board is of the opinion that the Syncrude proposal is satisfactory since its contribution to calculated ground level concentrations in the overlap area is within one-half of the provincial standard but that the situation indicated by the calculations will have to be further appraised before the Syncrude plant commences operation.

The Board agrees with the applicants that installation of additional sulphur recovery equipment is not technically feasible at this time. If the Board should approve the present application it will review the situation in the future and may eventually require the installation of additional equipment to reduce sulphur dioxide emissions.

The Board staff calculated the nitrogen oxides concentrations that would result from the stack emissions. The maximum calculated concentration of nitrogen oxides, expressed as nitrogen dioxide, at ground level was 0.04 parts per million. This concentration is higher than that calculated by Syncrude but is well below the provincial standard of 0.3 parts per million and hence satisfactory to the Board.

The Board reviewed the particulate emission rates calculated by Syncrude and is satisfied, on the basis of the data presented, that the provincial standard would be met. The Board would, however, require a higher dust collector efficiency if the provincial standard should be modified to a more stringent level.

The Board is of the opinion that if this application is granted, the proposed air pollution monitoring network should contain a minimum of 25 exposure cylinders. The number and location of the cylinders would be determined in consultation with the Board and the Department of the Environment. The plan of the applicants to isolate from any flowing body of water their water storage, settling and handling facilities is satisfactory to the Board but would be subject to the requirements of the Board and of the Department of the Environment as to the details of the installation and operation of the system.

Although the Board is of the opinion that the surface restoration and revegetation plans of the applicants are adequate, any approval of the application would be subject to the condition that the applicants satisfy the Board and any other Department or Agencies of the Government having jurisdiction with respect to the details of these plans.

The Board believes that should the application be granted it would be appropriate to amend Approval No. 1223 to include the requirements regarding pollution control at the plant.

VII QUALIFICATION UNDER THE OIL SANDS DEVELOPMENT POLICY AND THE LIFE INDEX OF ALBERTA'S PRORATABLE CRUDE OIL RESERVES

The Board received evidence in the form of submissions and testimony regarding a variety of developments which affect the future trend in the life index of the Province's proratable crude oil reserves. The life index relates the level of reserves to demand for Alberta proratable crude oil.

(1) Views of the Applicants

The applicants submitted estimates, presented in Table VII-8, which showed a decline in the life index from a level of some 24 years at year-end 1970, to a level of 10 years at the end of 1977. In the light of these estimates the applicants contended that the current application would qualify under the life index criterion of the Oil Sands Development Policy. This life index calculation was based on an assessment of future supply and demand conditions in both Canada and the United States, and on an assessment of reserve growth and other developments within Alberta.

The applicants forecast that United States demand for liquid hydrocarbons would expand at an average annual growth rate of 5.2 per cent over the period 1970 to 1980, from 14.5 million barrels per day to 24.0 million barrels per day. They projected that, during the same period, United States production would increase slightly from 11.3 million barrels per day to 12.9 million barrels per day. The demand and production schedules are presented in Table VII-1.

At the hearing, the witness for the applicants dealing with this portion of the application explained that the estimates of demand in the United States which were substantially higher than those submitted at the 1969 hearing, had been calculated within the context of a forecast of overall energy demand, and that the higher rate of growth was a reflection of current trends. Increases in the apparent energy requirement per dollar of Gross National Product were cited in support of the higher estimate of total energy requirements for 1980 of 106 quadrillion Btu, and limitations on the availability of competing fuels were expected to further stimulate demand for petroleum.

The applicants' United States production schedule was developed from projections of regional conventional oil production and synthetic oil production. Conventioanl oil production in the contiguous 48 states was forecast to peak in 1973 at some 11.6 million barrels per day, declining to 10.0 million barrels per day by 1980. Incorporated in this forecast was the assumption that spare productive capacity, excluding the Elk Hills Naval Reserve, would disappear by 1973. Due to competitive conditions the applicants did not offer estimates of Alaska North Slope production, but incorporated a slightly modified version of the Board's High Case, which was previously published in OGCB Report 69-C(1), stating that this estimate, with production rising from

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(1) Report of an Application of Atlantic Richfield Company, Cities Service Athabasca, Inc., Imperial Oil Limited and Royalite Oil Company, Limited. September 1969.

1.0 million barrels per day in 1975 to 2.8 million barrels per day in 1980, was broadly representative of their expectations. Minor volumes of synthetic oil production, from oil shale, were forecast for the later years of the forecast period, 50 thousand barrels per day in 1977 to 1979, rising to 100 thousand barrels per day in 1980. The applicants preferred not to reveal the price assumptions utilized in the production forecast, although it was stated that over the period increases in wellhead prices would probably more than compensate for inflation.

Combining the demand and production schedules results in a deficiency of United States oil supply rising from some 3.2 million barrels per day in 1970, to 7.2 and 11.2 million barrels per day in 1976 and 1980 respectively. The applicants' forecast of oil imports by area is shown in Table VII-2. This forecast was based on assumptions that Western Hemisphere sources, excluding Canada, would be unable to expand exports from current levels, and that the United States Oil Import Policy would be structured so as to favour relatively secure sources of imports, and particularly Canada, in order to minimize dependence on imports from the Eastern Hemisphere. The witness expressed an expectation that policy restraints on imports of Canadian oil into Districts I to IV would be removed for the year 1973, but the schedule of Canadian exports was calculated by adding moderate increases each year, rather than projecting a sudden increase in production to capacity level. After 1976 Canadian productive capacity would be the limiting factor, with Alberta volumes based on a life index of 10 years for proratable crude oil. The applicants rejected the view that the United States Government might adjust the Oil Import Policy so as to maintain Canadian capability as an emergency reserve, citing the size of the domestic deficiency, and the intergovernmental discussions, as evidence for this opinion.

Canadian demand for Western Canadian crude oil and pentanes plus was forecast to grow at an annual average rate of 4.7 per cent. As with the United States forecast, this petroleum demand schedule, presented in Table VII-4, was developed with reference to requirements for all types of energy. In addition allowance was made for continued movement of products across the National Oil Policy line at current levels. It was further assumed that The Hydro-Electric Power Commission of Ontario's ("Ontario Hydro") forecast petroleum requirements would be supplied from Western Canadian sources.

The applicants' forecast of Western Canadian production, excluding Alberta, is shown in Table VII-5. British Columbia production was projected to continue at current levels of 70 thousand barrels per day, while Saskatchewan production was forecast to decline from 246 to 130 thousand barrels per day over the period 1970 to 1980. The forecast for the Yukon and Northwest Territories included minor amounts from Southern areas during the latter half of the period, plus substantial volumes from the MacKenzie Delta area in 1979 to 1980. It was the witness's opinion that these volumes, plus additional Alaska North Slope volumes excess to the capacity of the proposed

Alyeska pipe line, would be sufficient to support a pipe line through the Mackenzie Valley. The applicants also stated their belief that any production from East Coast discoveries would be marketed East of the National Oil Policy line, or exported to the United States.

The applicants' forecast of Alberta production of crude oil and pentanes plus is shown in Table VII-6. The synthetic oil production reflects volumes from the Great Canadian Oil Sands plant, with an assumed additional 20 thousand barrels per day from 1975 to 1980, plus the volumes applied for in the current application, plus an allowance for other unspecified schemes.

As mentioned previously the applicants' forecast of Alberta production of proratable crude oil was based on market demand consideration for the early years of the period, while estimates for later years were developed on the basis of an acceptable rate of decline of the life index with a minimum level of ten years. Table VII-8 details the growth in reserves forecast by the applicants, and the associated life index. The declining trend in annual additions, from 400 million barrels in 1971 to 270 million barrels in 1977, was based on historical trends and, in particular, experience in recent years. The production levels were also examined in relation to recent industry estimates of expansion in productive capacity.

(2) Views of the Board

In assessing the application the Board has found it useful to compare the applicants' estimates with those of an independent study carried out by the Board staff earlier this year. The relevant features of the Board staff's forecast are reproduced in Table VII-1 to VII-9.

The applicants' and the staff's projections of United States petroleum demand are in broad agreement for the period 1970 through 1976. However, in subsequent years there is an increasing divergence, with the applicants' estimate for 1980 some 2.2 million barrels per day greater. Although it has been impossible to make detailed comparisons of the two studies, it appears that the greater part of this divergence is due to differing assumptions with regard to the supply of competing fuels, especially natural gas, as both energy studies forecast a 1980 total primary energy requirement of some 106 quadrillion Btu.

The forecasts also differ with respect to total United States oil production. This appears to have been mainly due to differing assumptions regarding well head prices and reserve growth in the contiguous 48 states, and to differing estimates of production for the Alaska North Slope and the development of synthetic crude oil capacity.

Although the applicants' and Board staff estimates of United States domestic supply deficiency differ with respect to the degree of deficiency, both forecasts agree that the

United States is faced with a significant and increasing degree of dependency on petroleum imports, although the absolute level of the deficiency may be subject to interpretation.

The Board staff's forecast of United States imports is presented in Table VII-3. The schedules for Canadian imports were developed on the assumption that the United States policy restraints on imports would be removed in 1974, and that in 1974 and subsequent years, the level of imports from Canada would be determined by the growth in Canadian producing capability and the need to supply Canadian requirements. Due to the production assumptions underlying the staff's analysis, the level of Canadian imports declines over the period 1975 to 1978. In contrast the applicants' forecast envisages imports rising fairly steadily throughout the period.

The Board agrees with the conclusions of the applicants and the Board staff that larger supply deficiencies will occur in the United States than was forecast in OGCB Report 69-C(1), providing greater opportunities for Canadian oil exports. The Board broadly agrees with the two forecasts, but considers a sudden increase in exports to be unlikely, in view of capacity restraints, normal supply arrangements of individual refineries, and United States policy objectives. In the Board's view planned and gradual increases would be the most probable and realistic forecast for Canadian exports. The Board's estimate of crude oil exports to the United States is shown in Table VII-10.

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(1) Report of an application of Atlantic Richfield Company, Cities Service Athabasca, Inc., Imperial Oil Limited and Royalite Oil Company, Limited. September 1969.

With regard to Canadian demand for Western Canadian petroleum, the Board staff projected a somewhat higher rate of growth than the applicants, with demand levels some 30 thousand barrels per day higher in 1977, and some 45 thousand barrels per day higher in 1980. The Board notes that the divergence would have been greater if the staff had assumed, as did the applicants, that Ontario Hydro requirements were to be supplied by Western Canada. The Board believes that the staff's estimate, as the higher of the two relatively similar forecasts, should be used in calculating demand for Alberta petroleum.

There are relatively minor differences between the two forecasts of Western Canadian production excluding Alberta. In the established areas the Board staff forecast a more moderate decline than the applicants, as shown in Table VII-5, resulting in production of some 30 thousand barrels per day greater in 1977, and some 50 thousand barrels per day greater in 1980. This difference is mainly attributable to the staff's higher forecast of Saskatchewan production. The staff forecast constant production of three thousand barrels a day from the southern portion of the Yukon and Northwest Territories for the period 1971 through 1978, in contrast to the applicants' forecast of additional and increasing volumes commencing in 1975. In addition the staff forecast higher production volumes from northern areas, in 1979 and 1980, than the applicants. The Board is of the opinion that the estimates submitted by the applicants and those calculated by the Board staff provide a reasonable range of production levels and has adopted an average of the two forecasts. The Board's estimate of total production excluding Alberta is presented in Table VII-10.

Alberta production of proratable crude oil was forecast by the Board staff, for the years following 1973, by assuming full utilization of capacity, defined as annual production at a 12 year life index, thus allowing for peak production at the MER capacity, which was assumed to equal a ten year life index. In forecasting proratable production the Board staff employed three estimates of Alberta reserve growth, which are shown as "high", "low" and "medium" on Table VII-9. The low and medium reserve forecasts were based on the expected appreciation of proved reserves and estimates of new discoveries during the forecast period and their appreciation over time. The primary difference between the two forecasts is the level of discoveries assumed. The high reserve forecast was taken as being somewhat higher than the average long term oil reserve growth rate.

The Board staff estimates and the one provided by the applicant are illustrated in Figure VII-1. The Board believes that the staff's high reserve forecast is an optimistic prediction having regard to the relatively low growth rates experienced in the past few years. On the other hand the staff's low reserve forecast appears pessimistic particularly in the later years. For the purpose of assessing the subject application the Board has modified the staff's forecast and has adopted a high and a low reserve forecast. The former is less than the Board staff's high forecast whereas the latter is greater than the staff low forecast in the later years. The applicants' forecast of reserve growth falls between the two Board forecasts, being close to the high forecast in the early years but declining so that by 1977 it is approaching the low forecast. The Board forecasts are shown in Table VII-11 and by the shaded area in Figure VII-1.

The applicants, Board staff, and Board forecasts result in similar predictions of the life index. In each case the index declines sharply in the initial years and by 1976, the year the proposed plant would be placed on production, the forecasts indicate a range of life indices of 11 to 13 years. In the Board's view this range reasonably spans the uncertainties of the forecast in 1976 as do the life indicies based on the Board's high and low reserve forecast for the full forecast period. The Oil Sands Development Policy requires that under the life index criterion "the scale and timing of increments of oil sands production" would be related to "the life index of conventional oil........ensuring that it does not drop below 12 to 13 years". The Board concludes therefore that the application qualifies under the life index criterion of the Oil

Sands Development Policy. Furthermore, the Board is satisfied that the synthetic crude oil production proposed by the applicant will supplement and not displace conventional crude oil production in Alberta.

VIII PIPE LINE CAPACITY CONSTRAINTS ON ALBERTA CONVENTIONAL PRODUCTION

(1) Views of the Applicants

Witnesses for the applicants expressed confidence that there would be sufficient capacity added to the Interprovincial Pipe Line Company ("Interprovincial") system to meet future increases in provincial production. However, the applicants rejected the IPAC proposal for a condition to be added to an approval to allow priority to conventional crude products in the event of inadequate Interprovincial capacity. A letter from Interprovincial to Syncrude was submitted, in which it was stated that Interprovincial's policy was to provide sufficient capacity to meet foreseeable demands on its transportation system, and that Interprovincial would be prepared to provide the necessary transportation facilities in respect of the additional production for the proposed plant without impinging on the capacity available for conventional crude oil production.

(2) Views of IPAC

IPAC's submission requested that in the event of the current application, and any similar application in the future, being granted, a provision should be included "whereby conventional crude products receive priority in ex-Alberta pipeline capacity, in the event that a shortage of pipeline capacity develops". The witness for IPAC emphasized that the intervention was not in opposition to the application, but reflected the Association's concern that unless new transportation facilities were constructed before the proposed plant began operations, the volumes of synthetic production might result in inadequate pipe line capacity, with consequent reductions in conventional production. IPAC contended that if such a situation occurred it would be a contravention of the Oil Sands Development Policy, which is to ensure that synthetic production supplement, and not displace, conventional production. It was stated that IPAC's concern would be considerably allayed if new facilities, which in IPAC's opinion entailed the addition of loops to the existing Interprovincial pipe line system, were to be announced, and construction commenced in the near future.

(3) Views of the Board

The Board believes that reasonable assurances were given at the hearing regarding Interprovincial's willingness to provide adequate capacity to handle production from the proposed Syncrude plant, and that conventional production would not be displaced as a result of the approval of the current application. The announcement by Interprovincial that it plans to commence looping its pipe line with 48-inch diameter pipe appears to confirm these assurances. The Board has concluded therefore that a condition of the form requested by IPAC is not necessary to the approval of the current application.

TABLE VII-1

Comparison of Applicants and Board Staff Estimates of United States Total Liquid Hydrocarbons Deficiency

(thousands of barrels per day)

Year	Applicants			Board Staff		
	United States Demand(1) (1)	United States Production(2) (2)	Deficiency (3)	United States Demand(1) (4)	United States Production(2) (5)	Deficiency (6)
1970	14,479	11,311	3,168	14,363	11,143	3,220
1971	15,080	11,400	3,680	14,850	11,320	3,530
1972	15,810	11,390	4,420	15,420	11,300	4,110
1973	16,500	11,630	4,870	16,240	11,080	5,150
1974	17,250	11,510	5,740	17,350	10,860	6,490
1975	18,290	12,140	6,150	18,160	11,310	6,850
1976	19,340	12,130	7,210	19,130	11,430	7,700
1977	20,180	12,280	7,900	19,690	11,790	7,900
1978	21,350	12,460	8,890	20,450	12,290	8,160
1979	22,610	12,650	9,960	21,080	12,910	8,170
1980	23,980	12,900	11,080	21,840	13,540	8,290

(1) Board Basis Demand
(2) Including Synthetic Oil Production

TABLE VII-2

Applicants
Estimated United States Imports of Total Liquid Hydrocarbons
(thousands of barrels per day)

Year	Assumed W. Hemisphere (ex Canada) (1)	Canada (2)	Gap for E. Hemisphere (3)	Total (4)
1970	1,915	733	520	3,168
1971	2,000	860	820	3,680
1972	2,000	1,000	1,420	4,420
1973	2,000	1,220	1,650	4,870
1974	2,000	1,430	2,310	5,740
1975	2,000	1,430	2,720	6,150
1976	2,000	1,440	3,770	7,210
1977	2,000	1,580	4,320	7,900
1978	2,000	1,520	5,370	8,890
1979	2,000	1,650	6,310	9,960
1980	2,000	1,760	7,320	11,080

TABLE VII-3

Board Staff
Estimated United States Imports of Total Liquid Hydrocarbons
(thousands of barrels per day)

Year	W.Hemisphere (ex Canada) (1)	Canada[1] Low (2)	Canada[1] Medium (3)	Canada[1] High (4)	E.Hemisphere[2] Low (5)	E.Hemisphere[2] Medium (6)	E.Hemisphere[2] High (7)	Total (8)
1970	2,000		735			485		3,220
1971	2,100		850			580		3,530
1972	2,200		1,020			890		4,110
1973	2,300		1,120			1,730		5,150
1974	2,450	1,330	1,410	1,490	2,710	2,630	2,540	6,490
1975	2,600	1,220	1,330	1,430	3,020	2,910	2,820	6,850
1976	2,750	1,180	1,320	1,430	3,770	3,630	3,520	7,700
1977	2,850	1,080	1,250	1,370	3,970	3,800	3,680	7,900
1978	2,950	960	1,160	1,300	4,240	4,050	3,910	8,160
1979	3,000	1,150	1,370	1,530	4,020	3,800	3,630	8,170
1980	3,100	1,330	1,570	1,760	3,860	3,620	3,430	8,290

(1) Low, medium and high cases for Canadian imports correspond respectively to low, medium and high cases for Alberta reserves growth.

(2) Converse of low, medium and high cases for Canadian imports.

TABLE VII-4

Comparison of Applicants and Board Staff Estimates of Domestic Demand and Total Demand for Canadian Oil(1)

(thousands of barrels per day)

Year	Applicants		Board Staff			
	Domestic Demand (1)	Total Demand(2) (2)	Domestic Demand (3)	Total Demand(2) Low (4)	Medium (5)	High (6)
1970	712	1,382	709		1,444	
1971	725	1,500	730		1,530	
1972	755	1,655	770		1,730	
1973	790	1,890	810		1,860	
1974	820	2,120	840	2,090	2,170	2,260
1975	855	2,155	880	2,020	2,130	2,230
1976	890	2,190	920	2,020	2,160	2,270
1977	930	2,370	960	1,950	2,120	2,250
1978	965	2,345	1,000	1,890	2,080	2,220
1979	1,005	2,520	1,050	2,120	2,340	2,500
1980	1,050	2,680	1,100	2,340	2,590	2,770

(1) Crude Oil and Pentanes Plus

(2) Including export demand, adjusted to exclude liquid hydrocarbons other than crude oil and pentanes plus

TABLE VII-5

Applicants and Board Staff
Estimated Supply of Canadian Oil(1) outside Alberta
(thousands of barrels per day)

	Applicants			Board Staff		
Year	Established Areas(2) (1)	Yukon and NWT (2)	Total (3)	Established Areas(2) (4)	Yukon and NWT (5)	Total (6)
1970	337	3	340	337	3	340
1971	327	3	330	337	3	340
1972	317	3	320	331	3	334
1973	307	3	310	321	3	324
1974	292	3	295	310	3	313
1975	278	20	298	299	3	302
1976	262	40	302	283	3	286
1977	252	60	312	277	3	280
1978	241	90	331	273	3	276
1979	231	320	551	272	300	572
1980	220	525	745	268	600	868

(1) Crude Oil and Pentanes Plus
(2) Saskatchewan, Manitoba, British Columbia and Ontario

TABLE VII-6

Applicants
Estimated Alberta Oil(1) Production
(thousands of barrels per day)

Year	Synthetic (1)	Pentanes Plus (2)	Non-Proratable Conventional Crude Oil(2) (3)	Proratable Crude Oil (4)	Total (5)
1970	33	117	52	840	1,042
1971	40	145	50	935	1,170
1972	45	163	52	1,075	1,335
1973	45	169	51	1,315	1,580
1974	45	172	48	1,560	1,825
1975	65	170	52	1,570	1,857
1976	100	167	51	1,570	1,888
1977	150	166	50	1,690	2,056
1978	200	163	51	1,600	2,014
1979	250	156	48	1,515	1,969
1980	300	152	48	1,435	1,935

(1) Crude Oil and Pentanes Plus
(2) Conventional Heavy Crude Oil and Good Production Practice

TABLE VII-7

Board Staff
Estimated Alberta Oil(1) Production
(thousands of barrels per day)

Year	Synthetic(2) (1)	Pentanes Plus (2)	Non-Proratable Conventional Crude Oil(3) (3)	Proratable			Total		
				Low (4)	Medium (5)	High (6)	Low (7)	Medium (8)	High (9)
1970	33	116	50		840			1,039	
1971	40	140	50		963			1,193	
1972	45	176	50		1,119			1,390	
1973	45	175	50		1,265			1,535	
1974	45	174	50	1,510	1,586	1,674	1,779	1,855	1,943
1975	45	178	50	1,444	1,553	1,652	1,717	1,826	1,925
1976	125	180	50	1,377	1,516	1,626	1,732	1,871	1,981
1977	125	182	50	1,318	1,488	1,611	1,675	1,845	1,968
1978	125	180	50	1,255	1,449	1,592	1,610	1,804	1,947
1979	125	178	50	1,192	1,411	1,575	1,545	1,764	1,928
1980	125	176	50	1,126	1,369	1,555	1,477	1,720	1,906

(1) Crude Oil and Pentanes Plus
(2) GCOS authorized capacity, plus currently authorized Syncrude capacity.
(3) Conventional Heavy Crude Oil and Good Production Practice

TABLE VII-8

Applicants
Estimated Production, Reserves and Life Index of Alberta Proratable Crude Oil

Year	Ultimate Reserves (MM bbl) (1)	Production (Mb/d) (2)	Life Index (Years) (3)
1970	10,458	840	24.2
1971	10,860	935	21.9
1972	11,230	1,075	19.0
1973	11,570	1,315	15.2
1974	11,890	1,560	12.4
1975	12,190	1,570	11.9
1976	12,475	1,570	11.3
1977	12,745	1,690	10.0

TABLE VII-9

Board Staff
Estimated Production, Reserves and Life Index of Alberta Proratable Crude Oil

	Ultimate Reserves (MM Bbl)			Production (Mb/d)			Life Index (Years)		
Year	Low (1)	Medium (2)	High (3)	Low (4)	Medium (5)	High (6)	Low (7)	Medium (8)	High (9)
1970	10,460	10,460	10,460		840		24.2	24.2	24.2
1971	10,600	10,640	10,710		960		20.5	20.6	20.8
1972	10,830	11,010	11,210		1,120		17.1	17.6	18.1
1973	11,080	11,380	11,710		1,260		15.0	15.4	16.1
1974	11,330	11,790	12,210	1,510	1,590	1,670	12.0	12.0	12.0
1975	11,570	12,210	12,710	1,440	1,550	1,650	12.0	12.0	12.0
1976	11,790	12,620	13,210	1,380	1,520	1,630	12.0	12.0	12.0
1977	12,000	13,020	13,710	1,320	1,490	1,611	12.0	12.0	12.0
1978	12,180	13,390	14,210	1,250	1,450	1,590	12.0	12.0	12.0
1979	12,340	13,730	14,710	1,190	1,410	1,570	12.0	12.0	12.0
1980	12,470	14,060	15,210	1,130	1,370	1,550	12.0	12.0	12.0

TABLE VII - 10

BOARD

ESTIMATED DEMAND FOR ALBERTA CRUDE OIL AND PENTANES PLUS

(thousand barrels per day)

Year	Canadian Demand for Canadian Oil	Exports to United States	Total Demand for Canadian Oil	Canadian Production Excluding Alberta	Demand for Alberta Oil
1971	730	760	1,490	340	1,150
1972	770	900	1,670	330	1,340
1973	810	1,010	1,820	320	1,500
1974	840	1,110	1,950	310	1,640
1975	880	1,080	1,960	300	1,660
1976	920	1,180	2,100	300	1,800
1977	960	1,280	2,240	300	1,940
1978	1,000	1,380	2,380	310	2,070
1979	1,050	1,580	2,630	560	2,070
1980	1,100	1,780	2,880	800	2,080

TABLE VII - 11

BOARD

FORECAST OF ALBERTA PRORATABLE CRUDE OIL LIFE INDEX
(thousand barrels per day)

Year	Demand for Alberta Oil	Non-Proratable Production	Proratable Production	Reserve Addition(1)		Life Index(2)	
				Low	High	Low	High
1971	1,150	220	930	140	250	21.3	21.9
1972	1,340	270	1,070	230	400	18.0	19.0
1973	1,500	270	1,230	250	400	15.3	16.5
1974	1,640	270	1,370	250	400	13.2	14.5
1975	1,660	270	1,390	240	400	12.5	14.2
1976	1,800	320	1,480	230	400	11.2	13.0
1977	1,940	360	1,580	220	400	9.8	11.9
1978	2,070	360	1,710	210	400	8.4	10.6
1979	2,070	350	1,720	200	400	7.7	10.2
1980	2,080	350	1,730	190	400	6.9	9.8

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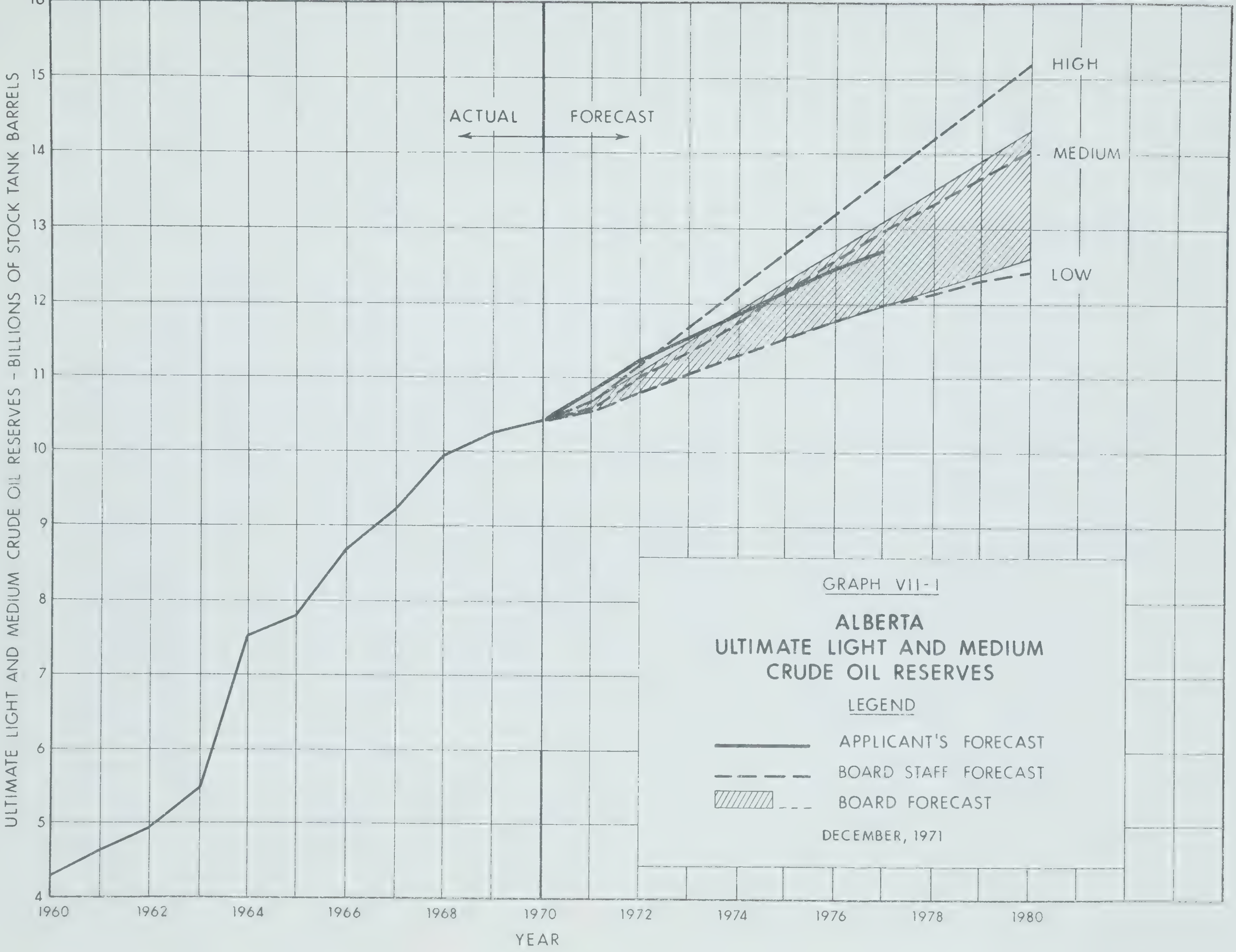
(1) Million Barrels of proratable crude oil.

(2) Years



GRAPH VII-1

**ALBERTA
ULTIMATE LIGHT AND MEDIUM
CRUDE OIL RESERVES**

DECEMBER, 1971

IX FINDINGS

The Board, having publicly heard the application for amendment of Approval No. 1223 under Part 8 of The Oil and Gas Conservation Act, of Atlantic Richfield Canada Ltd., Canada-Cities Service, Ltd., Gulf Oil Canada Limited and Imperial Oil Limited, and having studied the evidence submitted by the applicants and the interveners at the public hearing, and having regard to the advice of its staff and to its own knowledge, finds as follows:

1. THE CONSERVATION AND TECHNICAL ASPECTS

The applicants propose modest changes in their initial mining areas and a new method of oil sands excavation and transport. The Board considers these revisions to be desirable and likely to result in improved conservation. The revisions, the expansion of facilities to meet the increased production rates proposed, and other minor changes in the overall process, result in an estimated one per cent increase in overall recovery to 62 per cent, a level the Board considers satisfactory.

Details of these aspects are discussed in Section V of this report.

2. ENVIRONMENTAL PROTECTION

The scheme provides for control of emission to the air of sulphur, oxides of nitrogen and particulate matter at rates within the standards established for the Province, and is satisfactory to the Board in this respect. The general plans of the applicants for the prevention of any movement of process water beyond the lease boundary, and for reclamation of the mined out areas are also satisfactory, subject to the condition that the appropriate Departments and agencies of the Alberta Government be satisfied as to details.

The Board considers it desirable that the conditions of the existing approval relating to environmental matters be made more specific and amended to incorporate reference to new Provincial standards.

Details concerning environmental matters are given in Section VI hereof.

3. THE APPLICATION QUALIFYING UNDER THE OIL SAND DEVELOPMENT POLICY

The forecasts of life indices prepared by the applicants, the Board staff and the Board do not differ significantly. The Board believes that the life index of Alberta proratable crude oil reserves will decline sharply in the next few years and that by 1976, the year the proposed plant will be placed on production, the life index will be in the range of 11 to 13 years. The Oil Sands Development Policy prescribes that under the life index criterion additional oil sands production must be related to the life index of conventional oil, with the objective of maintaining it at 12 to 13 years. The Board concludes that the proposed application qualifies under this condition.

Details concerning the life index for Alberta conventional crude oil are discussed in Section VII hereof.

4. CAPACITY CONSTRAINTS ON ALBERTA CONVENTIONAL PRODUCTION

In the light of the assurances of Interprovincial Pipe Line Company, given at the hearing, of its intention to provide adequate capacity for the applicants' production, and in the light of the recent decision of that carrier to commence looping its pipe line with 48-inch diameter pipe, the Board does not consider it necessary to impose on the applicants a condition that conventional crude oil would receive priority in extra-provincial pipe line capacity in the event that a shortage in such capacity should develop.

This matter is discussed in Section VIII hereof.

5. DISPOSITION OF THE APPLICATION

Having regard for its present findings as reported in Findings 1 to 4 of this Section and its responsibility under The Oil and Gas Conservation Act, and the Oil Sands Development Policy of the Government of Alberta, the Board is prepared, with the approval of the Lieutenant Governor in Council, to grant the application, and to issue to the applicants an approval, superseding Approval No. 1223, in the form reproduced in Appendix A and subject to the terms and conditions therein contained.

Respectfully submitted,

G. W. Govier, P. Eng.
Chairman

D. R. Craig, P. Eng.
Vice Chairman

Vernon Millard
Vice Chairman

DATED at Calgary, Alberta
this 13th day of December, A.D. 1971

APPENDIX A

FORM OF APPROVAL

PROVINCE OF ALBERTA

THE OIL AND GAS CONSERVATION ACT

ENERGY RESOURCES CONSERVATION BOARD

IN THE MATTER of a scheme of Atlantic Richfield Canada Ltd., Canada-Cities Service, Ltd., Gulf Oil Canada Limited and Imperial Oil Limited for the recovery of oil sands, crude bitumen or products derived therefrom.

APPROVAL NO. ___

WHEREAS the Oil and Gas Conservation Board, now named the Energy Resources Conservation Board, by Approval No. 1223, dated September 30, 1969, approved a scheme of Atlantic Richfield Company, Cities Service Athabasca, Inc., Imperial Oil Limited and Royalite Oil Company, Limited for the recovery of oil sands, crude bitumen or products derived therefrom, and

WHEREAS Atlantic Richfield Canada Ltd., Canada-Cities Service, Ltd., Gulf Oil Canada Limited and Imperial Oil Limited, being the holders or the successors of holders of Approval No. 1223, have applied for amendment of the said Approval and it is proper and desirable that a new approval be issued superseding Approval No. 1223.

THEREFORE, the Energy Resources Conservation Board, pursuant to The Oil and Gas Conservation Act, being chapter 267 of the Revised Statutes of Alberta, 1970, and with the approval of the Lieutenant Governor in Council numbered O.C. /71 and dated 1971, hereby orders as follows:

1. (1) The scheme of Atlantic Richfield Canada Ltd., Canada-Cities Service, Ltd., Gulf Oil Canada Limited and Imperial Oil Limited, proposed to be developed and operated on their behalf by Syncrude Canada Ltd. (which five companies are hereinafter collectively called "Syncrude") for the recovery of oil sands, crude bitumen or products derived therefrom, taken from the area shown outlined on the attachment hereto, marked Appendix A to this approval, as such scheme is described in

(a) an application dated May 9, 1962, as amended to May 3, 1968 and to March 24, 1969, and supporting material marked as exhibits and evidence adduced at the hearings of the application and amendments thereof, and

(b) an application dated August 7, 1971, and supporting material marked as exhibits and evidence adduced at the hearing of the application,

is approved, subject to the terms and conditions herein contained.

(2) Subclause (1) does not preclude alterations in design or equipment compatible with the outlines of the scheme and made for the better operation of the scheme.

2. This approval applies to the recovery in each calendar year of 45,625,000 barrels of synthetic crude oil and 2,000,000 barrels of residual fuel in excess of that required by the

recovery process, but for the period consisting of the part of the year following the date, as established by the Board, of commencement of essentially full-scale operations, and the next succeeding calendar year, the above volumes shall be increased by multiplication by the factor equivalent to the number of days in the period divided by 365.

3. Prior to the commencement of major construction of the project facilities, Syncrude shall

(a) satisfy the Board that it would be economically feasible to remove and satisfactorily dispose of the tailings and overburden from the initial tailings disposal area described in the application referred to in clause 1, subclause (1), subclause (b), in order that satisfactory recovery of the oil sands reserves of the area would ultimately be possible, or

(b) propose alternative or modified initial tailings disposal arrangements satisfactory to the Board such that the impairment of recovery of oil sands reserves would be minimized.

4. Prior to the commencement of major construction Syncrude shall, in the month of December of each year, through a brief report of the progress of its experimental, pilot plant and engineering design work, satisfy the Board that it is proceeding generally in accordance with the schedule submitted to the Board at the September 1971 hearing of the application referred to in

clause 1, subclause (1), subclause (b).

5. Syncrude shall satisfy the Board, prior to June 1, 1974, that construction of the facilities required for the scheme has commenced, unless upon application by Syncrude a later date is stipulated by the Board.

6. During construction of the proposed facilities Syncrude shall inform the Board on a quarterly basis of the progress of construction and shall obtain the approval of the Board concerning any major changes in design.

7. (1) Upon completion of the construction of the facilities and prior to June 1, 1976, or such later date as the Board may stipulate, Syncrude shall file such details of the project design or operating procedures as the Board may require.

(2) Without derogating from the generality of subsection (1), at the time fixed in subsection (1), and thereafter as required, Syncrude shall satisfy the Board and other concerned Departments and agencies of the Government of Alberta in detail as to the methods by which restoration of surface and revegation will be done in mined out areas.

8. The effective commencement of the recovery of saleable hydrocarbon products shall be not earlier than January 1, 1976, and not later than January 1, 1977, unless upon application by Syncrude later dates are stipulated by the Board.

9. Syncrude shall measure materials mined and processed, intermediate and final products recovered and other plant streams as necessary, so that material balance and recovery

calculations for the extraction, upgrading and related processes may be made with reasonable accuracy and frequency.

10. Syncrude shall furnish to the Board, in such detail and at such times as may be set by the Board, monthly reports of the quantity and assay of oil sands mined and the quantity of all intermediate and final products recovered therefrom.

11. After the commencement of mining operations, Syncrude shall report, in the first three years on a semi-annual basis and thereafter as required by the Board, the percentage of the crude bitumen in place in the mined area recovered during the report period, and details of the proposed mining and overburden removal plans for the succeeding period.

12. There shall be no flaring or waste of liquid hydrocarbons produced except in cases of emergency, unless authorized in writing by the Board.

13. Syncrude shall carry out its operations to the satisfaction of the Board and in a manner that

(a) does not preclude or render more difficult the recovery of other oil sands recoverable by practical and reasonable operations,

(b) results in the mining of the practical maximum of all oil sands within the area being mined,

(c) results in the processing for the recovery of crude bitumen of the practical maximum of all oil sands mined,

(d) results in the recovery of the practical maximum of crude bitumen from the oil sands mined, and

(e) results in the recovery from the crude bitumen of the practical maximum of marketable products.

14. Syncrude shall carry out the solids disposal operations to the satisfaction of the Board, on lands to be approved by the Board, and in a manner that insures the stability of any tailings piles.

15. Syncrude shall dispose of any liquid wastes in a manner satisfactory to the Department of the Environment (Alberta) and the Board and in a manner that ensures that no oily or contaminative materials flow over the land or into any body of water, except as specifically provided for in the scheme as described in the applications referred to in clause 1, subclause (1).

16. (1) The emission of sulphur dioxide, and the sulphur dioxide equivalent of other sulphur compounds, to the atmosphere from the plant incinerator and boiler stack shall not exceed 485 long tons per day (243 long tons per day equivalent sulphur) or 10.1 long tons in any half hour period (5.05 long tons equivalent sulphur).

(2) The plant incinerator and boiler stack height shall be sufficient to maintain the maximum half-hour average ground level concentrations of sulphur dioxide within the standard prescribed for gas processing plants in the Oil and Gas Conservation Regulations and shall be a minimum of 400 feet.

(3) The plant incinerator and boiler stack flue gas emission temperature shall be a minimum of 500° Fahrenheit.

(4) The concentration of particulates in the effluent gas from the plant incinerator and boiler stack shall not exceed the allowable limits as specified in the regulations for the control of air pollution of the Department of the Environment.

17. (1) In the event of an emergency necessitating the flaring of sour gas or sour gaseous products of the process, Syncrude shall add sufficient fuel gas to the sour gas or products prior to the flaring to ensure complete combustion and to maintain the maximum half-hour average concentration of sulphur dioxide within the standard prescribed for gas processing plants in the Oil and Gas Conservation Regulations.

(2) The stacks for the flaring of sour gas, gaseous products of the process and hydrocarbon shall be of a height satisfactory to the Board and shall be equipped with a continuously burning pilot and an automatic flame igniter.

18. (1) Syncrude shall conduct at suitable time intervals six stack surveys per year for the determination of the volume rate of flow, concentration of particulates, composition and temperature of the effluent gases from the plant incinerator and boiler stack.

(2) In each year at least one of the stack samplings tests required by subclause (1) shall be made when the plant is operating at not less than 90 per cent of its maximum daily production rate, and at least three others of such tests shall be made when the plant is operating at not less than 75 per cent of its maximum daily production rate.

19. (1) Syncrude shall maintain a minimum network of 25 exposure cylinder stations for the detection of hydrogen sulphide and total sulphation in the plant vicinity and shall expand the network to include other locations that the Department of the Environment may deem necessary.

(2) Syncrude shall maintain a monitoring program, to the satisfaction of the Department of the Environment, to provide a continuous record of atmospheric sulphur dioxide concentration (by means of an instrument sensitive enough to read to 0.05 parts per million), wind speed, wind direction and atmospheric hydrogen sulphide concentration (by means of a 'spot tape' type of analyzer) for 12 months of each year from three mobile laboratories in the plant vicinity.

(3) If the Department of the Environment so requires, the monitoring program shall be expanded to include other types of analyzers.

20. (1) Syncrude shall summarize the results of all stack surveys and forward them to the Board as soon as they are, or can be made, available.

(2) Syncrude shall summarize the results of the observations required by clause 19 and forward them to the Department of the Environment as soon as they are, or can be made, available.

21. Syncrude, in operations pursuant to the scheme, shall comply with the provisions of any applicable Act or regulation of the Province of Alberta now enacted or made, or that any time hereafter may be enacted or made.

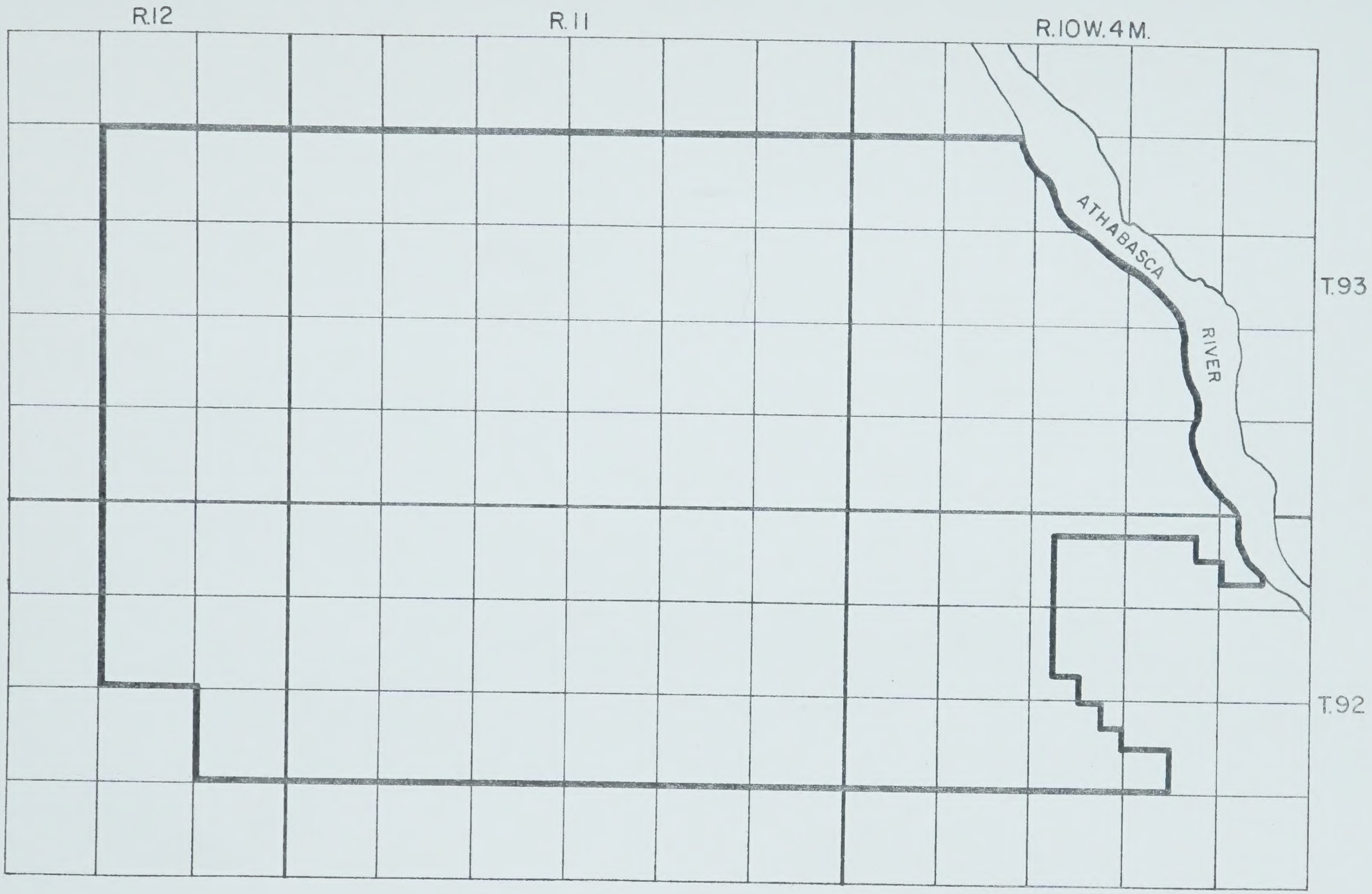
22. Where it appears to the Board that there has been a failure to comply with any terms or conditions of this approval, the Board may, in addition to any other remedy or proceeding to which it may resort, require the suspension of any operation carried on pursuant to the scheme.

23. This approval expires on December 31, 2001, unless rescinded before that date or unless the term of the approval is extended following a public hearing.

MADE at the City of Calgary, in the Province of Alberta, this day of December, A. D. 1971.

ENERGY RESOURCES CONSERVATION BOARD

G. W. Govier
Chairman



APPENDIX A TO APPROVAL NO.

ENERGY RESOURCES CONSERVATION BOARD
CALGARY, ALBERTA